CALIFORNIA'S ELECTRICITY GENERATION AND TRANSMISSION INTERCONNECTION NEEDS UNDER ALTERNATIVE SCENARIOS

Assessment of Resources, Demand, Need for Transmission Interconnections, Policy Issues, and Recommendations for Long Term Transmission Planning

CONSULTANT REPORT

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California Energy Commission

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March 2004
700-04-003

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FOREWORD

Electric Power Group (EPG), LLC prepared this report under the auspices of the Consortium of Electric Reliability Technology Solutions (CERTS)[1]. The CERTS Program Manager is Joseph Eto, Lawrence Berkeley National Laboratory. The project was funded by California Energy Commission, Don Kondoleon, Project Manager.

This report complements the study, Planning for California's Future Transmission Grid – Review of Transmission System, Strategic Benefits, Planning Issues and Policy Recommendations, which was completed in October 2003, for use by the California Energy Commission in its Integrated Energy Planning proceedings.

[1] CERTS is currently conducting research with funding from the U.S. Department of Energy (DOE) Transmission Reliability Program and the California Energy Commission. CERTS is working with electric power industry organizations, including ISOs, RTOs, NERC, and utilities. CERTS members include Electric Power Group, Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, National Science Foundation, Power Systems Engineering Research Center (PSERC), and Sandia National Laboratories.

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EXECUTIVE SUMMARY

Transmission interconnections have played a vital role in meeting California's electric needs. California currently has 18,170 MW (18.2 GW) of interconnections to neighboring states in the Western Interconnection, equivalent to approximately one-third of its annual peak electricity demand.

In planning for the transmission interconnections for the future, California has to look ahead 25 to 30 years to allow adequate lead time for corridor planning, transmission rights-of-way, and coordination with other states. Much of the existing interconnection system was planned 30 to 40 years ago. Transmission projects have a 10-year lead-time. Generation projects are planned with a much shorter lead-time. Hence, there is no reliable information on new power plant locations to guide long range transmission planning. Yet, if California does not start the early stages of planning for the longer term, the opportunity to site needed new transmission interconnections may be lost or become prohibitively expensive, just as in the case of building new freeways or airports in population centers.

Why are new transmission interconnections important for California and what should California do about it? These are important strategic questions to assure reliable and reasonably priced electricity to meet the needs of California's growing population and economy.

To address California transmission interconnections for the future, this study focused on the year 2030. By that time, California is forecast to experience:

- Population growth to over 50 million, an increase of 18 million over 30 years;
- Electricity peak demand of 80 GW, an increase of 28 GW from current levels, or an average annual peak demand growth of 1.5 percent;
- The existing stock of power plants capable of producing 60,000 MW (60 GW) declining to 32 GW (30 GW in-state and 2 GW out-of-state coal) assuming retirement of fossil plants 50 years or older and nuclear plants after first re-licensing;
- Total capacity requirements estimated at 92 GW, assuming a 15 percent reserve margin;
- 60 GW of new electric supplies will be needed to power California's economy in 2030;
- 69 GW of in-state generation and 23 GW of imports will be needed, assuming imports supply 25 percent of total capacity requirements;
- After plant retirements, remaining in-state capacity will be 30 GW, requiring 39 GW of new in-state capacity.

This report examines different scenarios for power plant development in and around the state. The state cannot meet all future needs with new gas-fired power plants, as has been the case recently. In the base case, 20 percent of energy is assumed to be supplied by renewable energy resources. This is equivalent to 18.3 GW, a fourfold increase from the 4.4 GW currently in operation. (Actual installed capacity may be two to three times that of peak capacity due to the intermittent nature of renewables.) Other scenarios assume a higher level of renewables, low load growth, and increased imports.

To supply 23 GW from imports, assuming 15 percent reserves for transmission[2], 26.5 GW of transmission will be required. Hence, the state needs to expand the current level of 18.2 GW of transmission interconnections by 8.3 GW to meet its future electricity needs. This requirement decreases to 6.1 GW under the low load growth scenario and increases to 13.5 GW if gas dependence is reduced through increased imports.

Several new interconnection projects are under discussion, including Devers-Palo Verde 2, with approximately 1,400 MW of capacity; doubling the interconnection between California and Baja Mexico, adding 800 MW of capacity; and doubling the interconnection to Utah, adding 2,000 MW of capacity. This still leaves a need to develop another 4,000 MW of interconnections in the base case and over 9,000 MW in the higher imports scenario as part of California's Grid of The Future.

Building interconnections to neighboring states will require coordinated planning on transmission corridors, rights-of-way, and transmission development. In addition, it is important to take steps now to preserve the flexibility for building these future interconnections. To address these long-term issues, California should take steps now, including:

- Developing a shared vision for California's Grid of The Future;
- Identifying strategic interconnections to existing and future regional market hubs;
- Coordinating planning efforts with neighboring states;
- Establishing a regulatory framework to support long term transmission infrastructure development;
- Authorizing utilities to acquire rights-of-way and bank them for future use.

This report is designed to help policymakers focus on the long-term and take steps now to plan for a robust and secure electricity infrastructure. Ultimately, a balanced and diversified resource strategy would utilize conservation, load management, renewables, distributed generation, and new interconnections and power plants. California also

[2] 100 percent of transmission cannot be used simultaneously at peak.

needs to plan for its future electricity needs by addressing other issues, e.g., fuel mix, energy efficiency, siting, transmission, and gas transportation. This report does not advocate any particular fuel source. It attempts to paint the situation in 2030 and concludes that new interconnections to resource-rich regions and new market hubs will be a part of California's future, and therefore California needs to take steps now to meet its future electricity needs.

INTRODUCTION

California currently has 18,170 MW (18.2 GW) of capability to import electricity from other states and Mexico. For 2002, California's peak electricity demand was about 52 GW. This means that current interconnection capability is about 35 percent of the annual peak demand.

Interconnections, such as Devers-Palo Verde 2 have been identified to increase California's import capability. Presently, the lead times for major transmission projects are very long. From the time a major transmission project is identified, to the time it becomes operational, can take ten years or more. It is therefore necessary to have a long planning horizon for transmission interconnection projects.

For this study, the Electric Power Group (EPG) selected the year 2030 to develop an outlook for electricity demand, generation resources and potential options for major transmission projects to add to California's existing import capability. This longer-term horizon is important to gain a perspective on the electricity infrastructure that will be needed to support California's growing population and economy.

This report provides information on expected population and demand growth; the current stock of power plants; the retirement outlook and future generation need; the transmission needed to increase import capability; alternative scenarios; and implications. This study relied on information on population, demand growth, natural gas and coal consumption, and fuel reserves from available public sources including data from the California Energy Commission (Energy Commission), Energy Information Administration (EIA), Western Electricity Coordinating Council (WECC), and others.

The last section of the report makes recommendations that address the key steps and policy decisions that need to be made to plan for California's transmission interconnections to meet future electricity needs.

POPULATION GROWTH AND ENERGY OUTLOOK

Population Growth

California is the most populous state of the nation, with 31.5 million people in 1995, and 12 percent of the nation's population. Based on a U.S. Bureau of Census projection, California's population will reach 49.3 million by 2025, a net increase of 17.8 million over a 30-year period. California is expected to be the fastest growing state during this period, as the population will increase by 56 percent from 1995-2025, forecasted to grow to 15 percent of the nation's population by 2025. International migration to California is the main reason for this rapid growth and is projected to be around 8.7 million, more than one-third of the immigrants, that will be added to the nation's population over the 30-year period.

Economic Growth

Based on the *Annual Energy Outlook* (*AEO*) 2003 prepared by the EIA, the U.S. economy as measured by gross domestic product (GDP) was projected to grow at an average annual rate of 3.0 percent during the 2001 to 2025 period.

Energy Growth and Demand

The *AEO* forecast for total energy consumption for the nation increases from 97.3 quadrillion Btu to 139.1 quadrillion Btu from 2001 to 2025, a 43 percent increase over the 24-year period. The annual average rate of growth is forecast at 1.0 percent, 1.6 percent, and 1.3 percent for residential, commercial, and industrial energy demand respectively, whereas transportation energy demand is projected to grow at an average annual rate of 2.0 percent over the same period.

The *AEO* projects that energy intensity, as measured by energy use per dollar of GDP, will continue to decline at an average annual rate of 1.5 percent through 2025 due to continued efficiency gains and structural shifts in the economy. However, per capita energy use is projected to increase by an average of 0.7 percent per year between 2001 and 2025.

Total electricity demand is projected by the *AEO* to grow by 1.8 percent per year from 2001 to 2025. Growth in electricity use for computers, office equipment, and a variety of electrical appliances, plus population growth, are the driving forces for the continuation of growth in this sector.

Total demand for natural gas is projected to increase at a similar rate, i.e., 1.8 percent per year between 2001 and 2025, primarily because of rapid growth in demand for electricity generation.

On the supply side, domestic natural gas production is projected to increase from 19.5 trillion cubic feet in 2001 to 26.8 trillion cubic feet by 2025. Domestic natural gas production is increasingly dependent on unconventional and more costly conventional resources both onshore and offshore in the lower 48 states. As the demand is larger than the domestic supply, an increasing share of U.S. gas demand will be met by imports from Canada, Mexico, and imported liquefied natural gas (LNG).

The *AEO* projects that net imports of natural gas will increase from 3.7 trillion cubic feet (16 percent of total demand) in 2001 to 7.8 trillion cubic feet (22 percent of total demand) in 2025.

U.S. coal production is projected to increase from 1,138 million short tons in 2001 to 1,440 million short tons by 2025. Net coal exports are expected to fall throughout 2001 to 2025 period.

Electricity generation from natural gas, coal, and renewable resources is projected to increase through 2025 as demand for electricity continues to grow. However, natural gas used for electricity generation will have the highest annual growth rate. The share of natural gas in the generation fuel mix increases from 17 percent in 2001 to 29 percent by 2025, an annual growth rate of 4.2 percent over the period.

The share from coal decreases from 52 percent in 2001 to 48 percent in 2025, although the *AEO* assumes that 70 GW of new coal-fired capacity will be constructed during the period 2001 to 2025. As no new nuclear capacity is being constructed, the share from nuclear also decreases from about 20 percent in 2001 to 14 percent by 2025.

Estimated recoverable U.S. coal reserves as of 2001 were around 5,500 quadrillion Btu and sufficient for 255 years at the 2001 level of consumption[3]. Over 50 percent of estimated U.S. recoverable coal reserve is in the Western United States. One-third of 2001 U.S. coal production was from Wyoming, with Montana the second leading coal producing state in the country. Coal is plentiful and, on a delivered basis, cost an average of $1.25/MMBtu in 2001. California cannot ignore these facts in long-term generation and transmission planning.

Total U.S. natural gas reserves at the end of 2001 were only 189 quadrillion Btu, i.e., less than 4 percent of current U.S. estimated recoverable coal reserve energy value, and sufficient to sustain only 8 years of consumption at the 2001 level. On the average,

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[3] Coal reserve quantities are 2001 recoverable coal reserves at producing mines, estimated recoverable reserves, and demonstrated reserves by mining method as reported by the EIA in the *Annual Coal Report*, 2001.

the U.S. natural gas reserve increases by approximately 22.6 quadrillion Btu per year, which is very close to the current level of consumption. However, the *AEO* projects that the annual consumption of natural gas will reach 35 quadrillion Btu by 2025. Although the *AEO* projects that 22 percent of year 2025 demand will be satisfied by imports, the remaining natural gas supply will decrease over time. By 2025 the *AEO* projects that national gas reserves will sustain less than 5 years of consumption.

There will be upward pressure on natural gas price as the remaining supply decreases over time. Price volatility will also increase. The impact of these factors on long-term generation and transmission planning should be recognized.

The increase in consumption of natural gas cannot be sustained for a long time from domestic U.S. and Canadian imports. Total natural gas reserves of these two countries are less than 5 percent of worldwide reserves. An increasing share of U.S. natural gas consumption will be met by imports, including LNG.

There are four existing U.S. LNG import facilities. Capacity expansion plans have been announced by three of these facilities. The *AEO* projects that imports will reach 22 percent of total demand in 2025 and that LNG will be an important share of these imports. In addition, the potential construction of an LNG terminal in Baja California will bring about construction of new power plants there and expansion of transmission from Mexico to California.

Renewable resources will play an important role in supplying California's growing electricity needs through development of additional wind, solar, geothermal, and biomass resources. For energy imports, California needs to look at resource- or generation-rich regions such as electricity generated from LNG in Baja California, gas and clean coal-based generation in the fossil fuel rich regions of Utah-Wyoming, and natural gas transported in pipelines to fuel power plants in California.

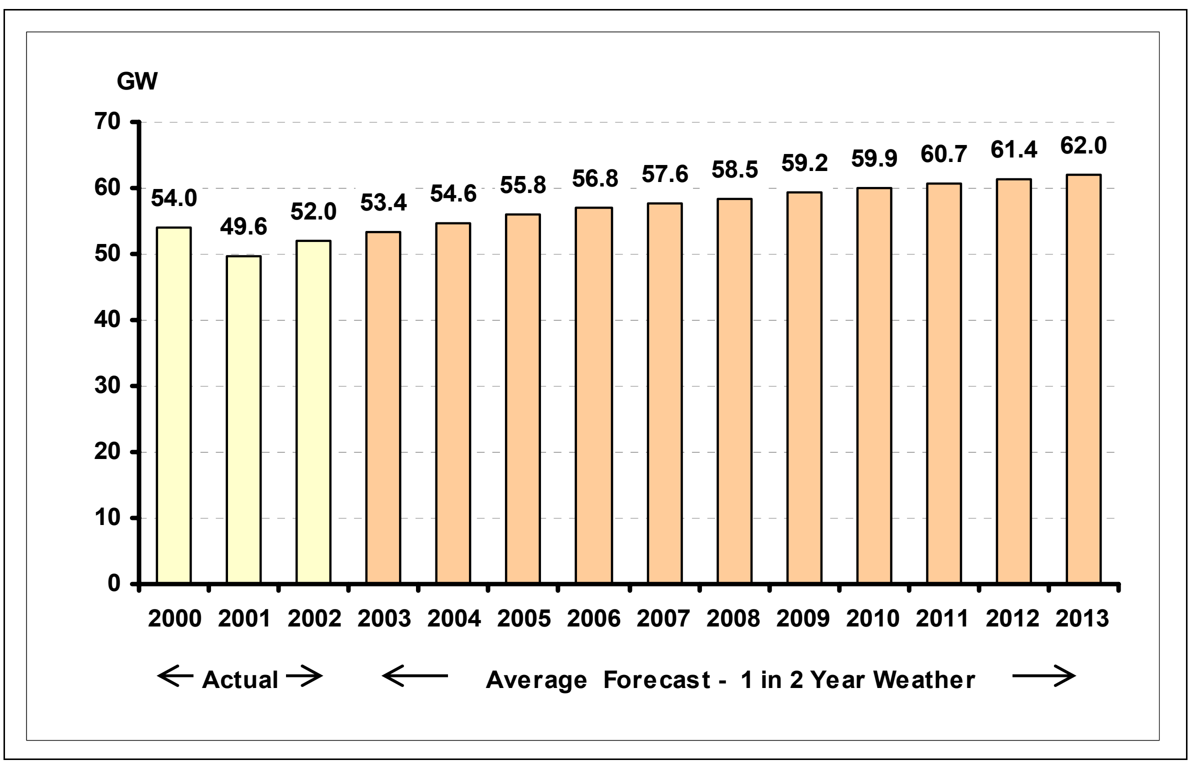
CALIFORNIA'S ELECTRICITY DEMAND AND GENERATION OUTLOOK

Demand for Electricity

California's growing population, which is forecast to be over 49 million by 2025 and over 53 million by 2030, will require about 92 GW of peak summer capacity in 2030 to meet demand and have an adequate reserve margin.

The Energy Commission staff report, *California Energy Demand 2003-2013 Forecast*, projects that peak demand in an average summer will increase from about 52 GW in 2002 to over 62 GW by 2013 (**Figure 1**). This means that due to population and economic growth the demand for electricity in California will grow at approximately 1.5 percent per year during this period. In the same report, the Energy Commission forecasts that Net Energy for Load will increase from 262 billion kWh in 2003 to 310 billion kWh by 2013 with an annual growth rate of 1.5 percent over the period.

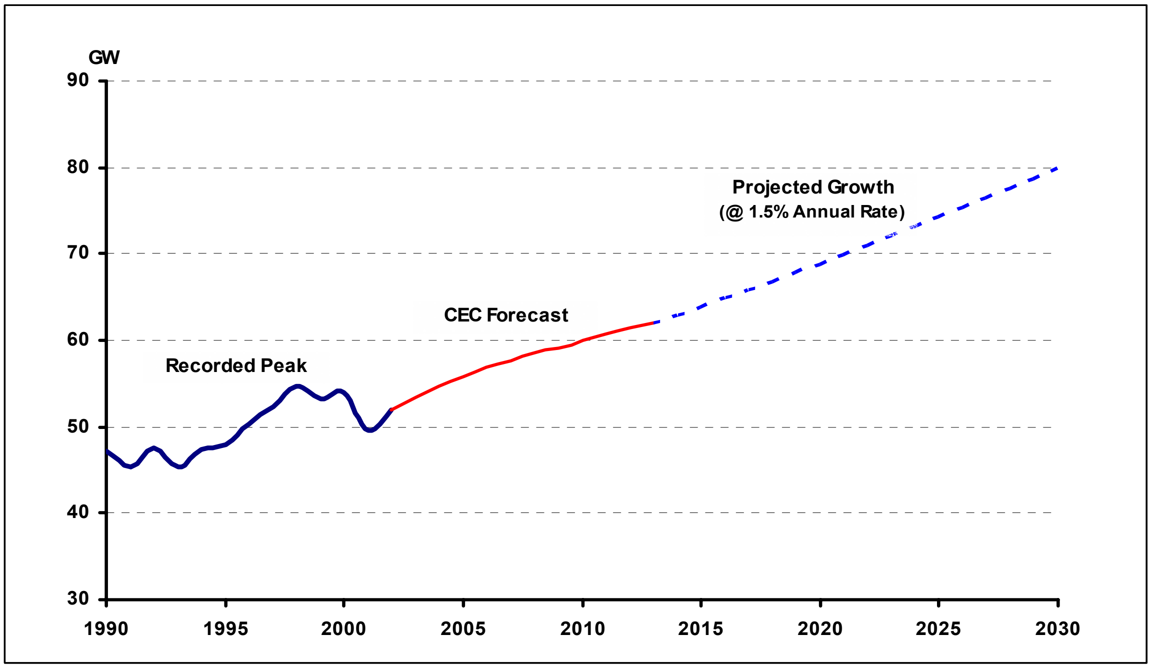
Figure 1
California Peak Demand (2000 to 2013)
(1 in 2 Year Weather, Net of Private Supply)



California has a history of energy conservation, demand management, and an economy with low energy intensity. Therefore, it is reasonable that despite high population growth compared to the rest of U.S., the electricity demand growth will be somewhat lower than the national average of 1.8 percent per year.

Assuming that California's peak demand will continue to grow at the same 1.5 percent annual rate of growth from 2013 to 2030, EPG estimates that peak demand will be about 80 GW by 2030 (**Figure 2**). When a 15 percent reserve margin is added, the capacity requirement will be nearly 92 GW. Assuming similar growth for energy, the annual net energy for load by 2030 will be about 400 billion kWh. These peak demand and the net energy for load do not include private supplies, generating electricity at a customer's site to satisfy all or a portion of the customer's need.

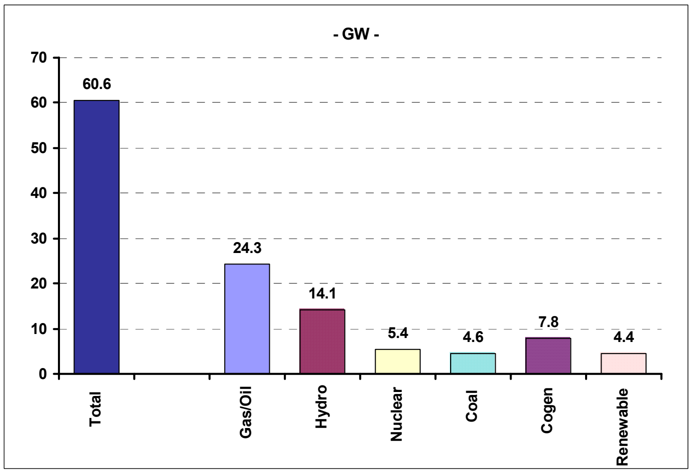
Figure 2
California Peak Demand Outlook through 2030

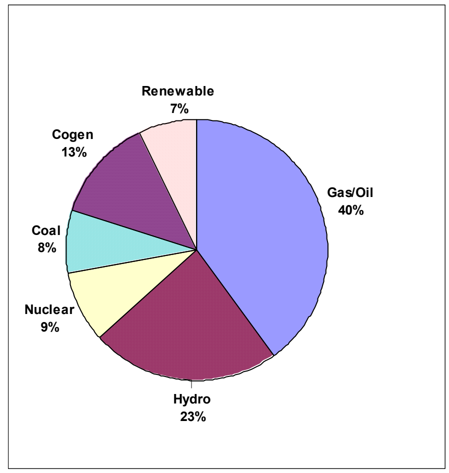


Current Generation Resources and Potential Retirement

As of January 2003, the existing generation capacity available to serve California's peak demand was 60.6 GW. **Figure 3** shows the mix of generation resources available to California at that time. About 40 percent of these resources were gas-fueled, owned by utilities and independent power producers or government agencies. In addition, cogeneration facilities that provide electricity to the utilities were 13 percent of existing capacity and mostly fueled with natural gas. Thus, over half of the generation available to California burned natural gas.

Figure 3
Existing Generation Resources Available to Serve California's Peak Demand (1/1/2003)

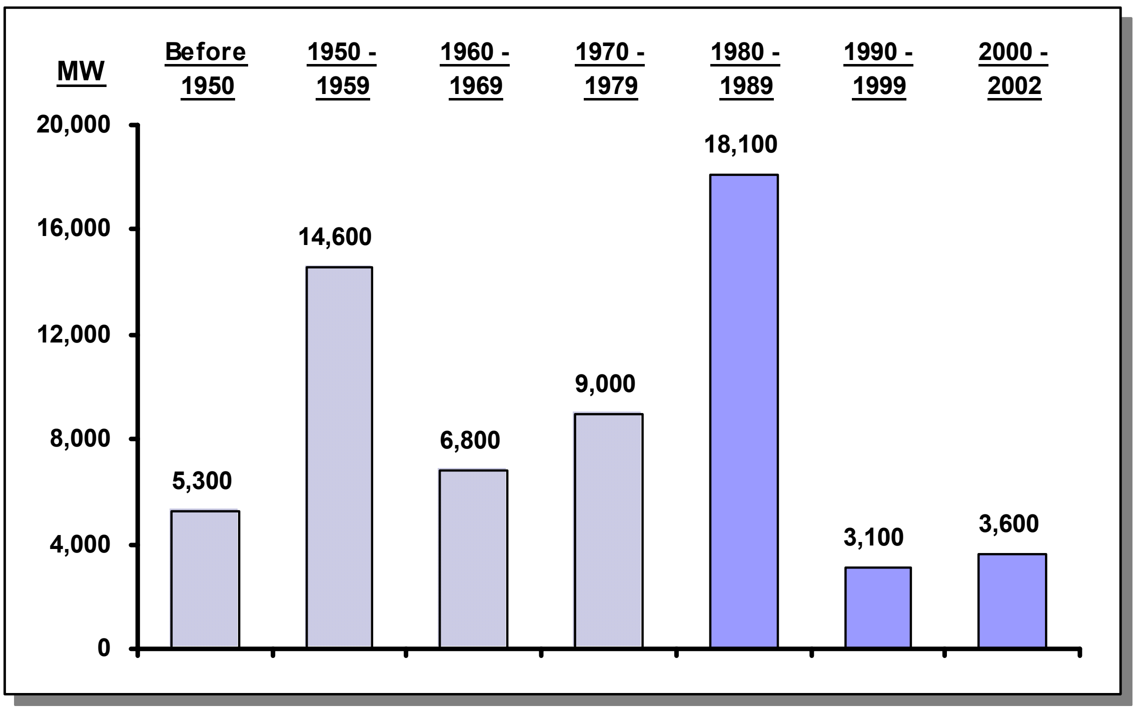




Source: Energy Commission *California Power Plants Database* (1/17/2001) and WECC *Proposed Generation Database* (8/8/2003)

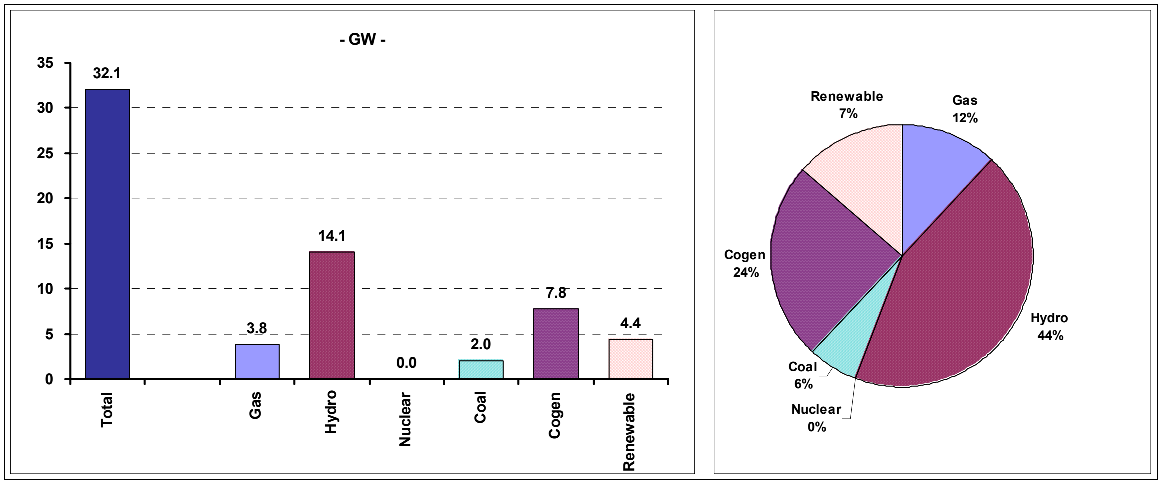
Out of 60.6 GW total existing generation capacity serving California, 35.7 GW became operational before 1980 (see **Figure 4**), and will be over 50 years old by 2030.

Figure 4
Age Distribution of Existing Power Plants Serving California
(Including Out of State Coal and Nuclear Plants Owned by California Utilities)



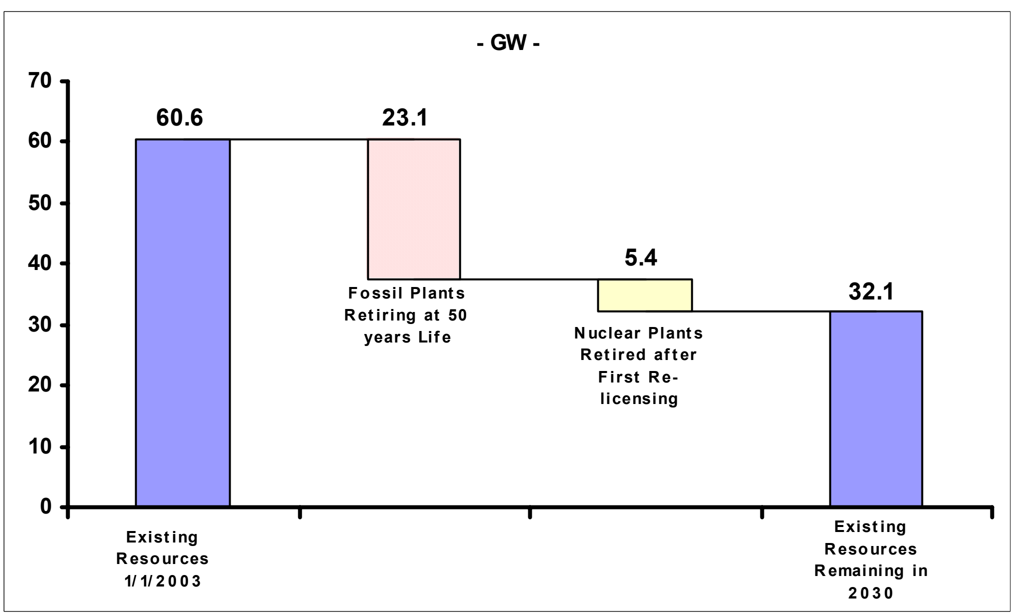
If all fossil-based power plants are retired after 50 years of operation and the state's three nuclear plants (San Onofre, Diablo Canyon, and Palo Verde) are retired after first re-licensings and will not be operating by 2030, then only 32.1 GW of the power plants in operation in 2003 will remain operational in 2030. **Figure 5** shows the fuel mix of the power plants that will remain in operation. These values assume that hydro resources will be re-licensed and will remain in operation; existing cogeneration and renewable resources will be retrofitted and repowered; and some coal plants will not have reached the retirement age of 50 (although they will be very close to it).

Figure 5
Resources Remaining after Retirement of Fossil Plants at 50 Years and Nuclear Plant Retirements



In summary, as shown in **Figure 6**, of the 60.6 GW of available resources as of January 2003, 23.1 GW of fossil plants would be retired at age 50, 5.4 GW of nuclear plants would be retired after first re-licensing, and only 32.1 GW, i.e., 53 percent of current resource portfolio, would remain operational.

Figure 6
Remaining Capacity in 2030 from the Current Portfolio



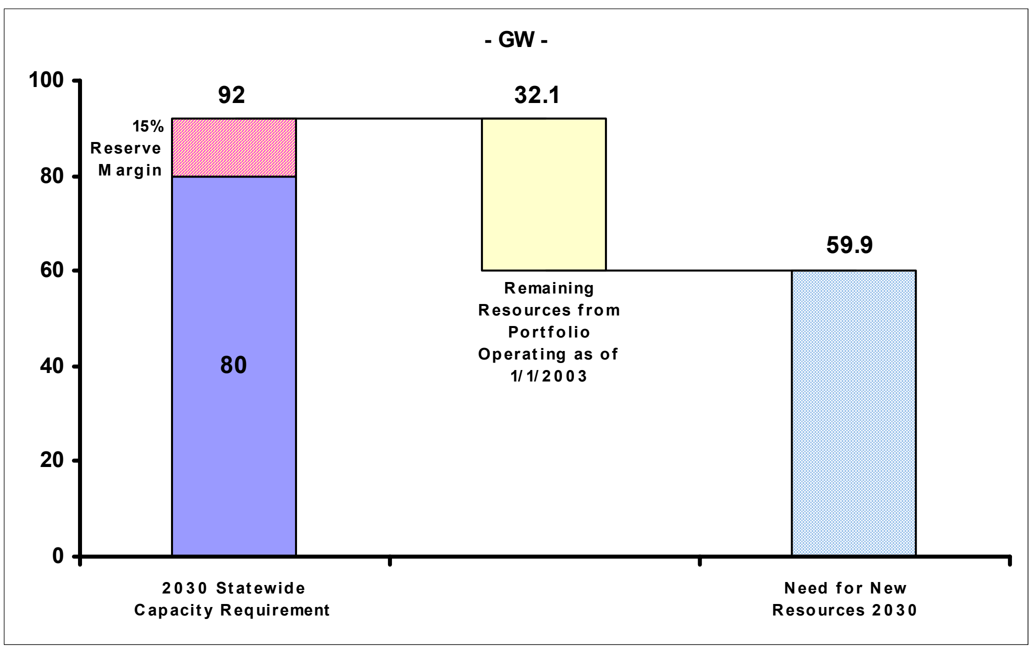
Source: Energy Commission, *Power Plants in California Report* (2/21/2003) and WECC Proposed Generation Database (8/8/2003)

Resource Needs for 2003-2030

With a 1.5 percent annual growth rate, the peak demand forecast for an average summer in California will be 80 GW by 2030. With a 15 percent planning reserve margin, the total capacity requirement will be 92 GW by 2030. Subtracting 32.1 GW of remaining resources from the January 2003 portfolio, the total need for resources will be 59.9 GW (**Figure 7**).

During the first eight months of 2003, seven new power plants became operational, the Sunrise Power Plant was converted to a combined cycle, and Huntington Beach No. 4 returned to active operation. The total capacity from these additions was 3,424 MW. Accounting for these additions, the remaining need for new capacity from September 2003 to summer 2030, a 27-year period, is expected to be 56.5 GW.

Figure 7
Need for New Resources During 2003-2030

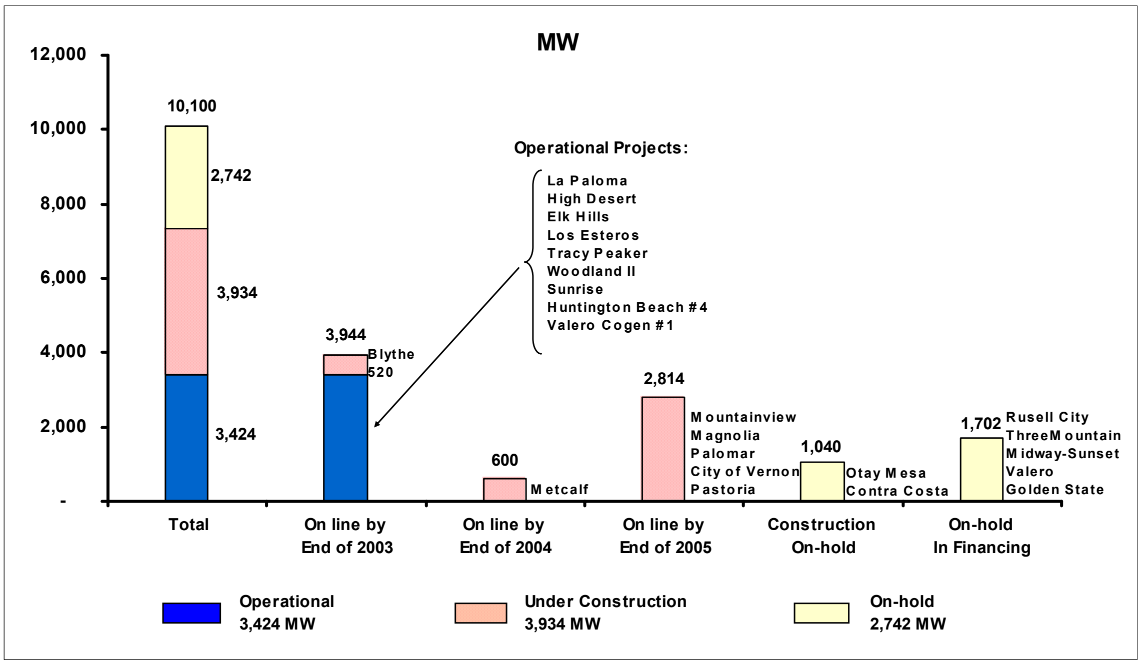


Generation Resources Identified

The Energy Commission publishes the *Energy Facility Status Report* that is updated frequently. The report lists projects that have obtained Energy Commission approvals (operational, under construction, or on hold); are under review; and have been announced.

Figure 8 is based on the *Energy Facility Status Report* of August 18, 2003 and shows all the projects that had obtained Energy Commission permits as of that date. The total capacity for these projects is 10,100 MW (this does not include East Altamont, 1,100 MW that was permitted on August 20, 2003). Of the 10,100 MW permitted capacity, 3,424 MW were operational by August 18, 2003; 3,934 MW were under construction and scheduled to come on-line from 2003 through end of 2005. Some projects, such as Mountainview and Palomar, may be delayed due to lack of long-term power procurement contracts. Projects with Energy Commission permits, but on hold, were 2,742 MW.

Figure 8
Projects with Energy Commission Permits



Source: Energy Commission, *Energy Facility Status Report* (8/18/2003)

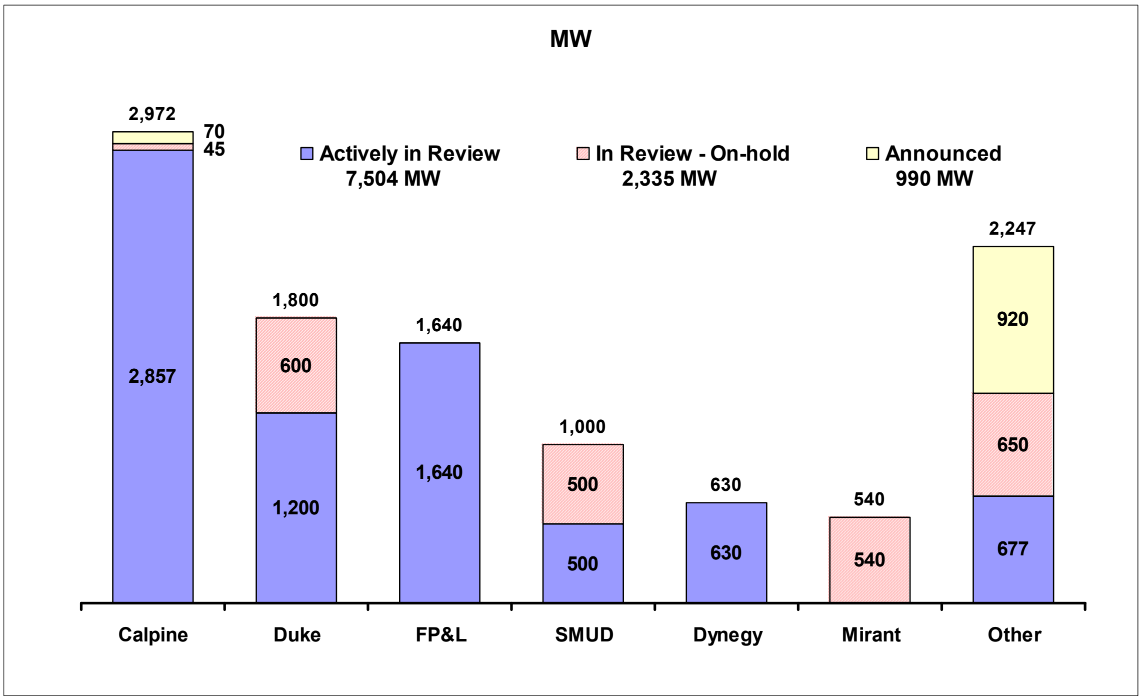
EPG assumes that all projects with Energy Commission approval will eventually be constructed and become operational as the utilities become creditworthy, regulatory issues are resolved, and the need for additional generation capacity is confirmed. **Table 1** provides the ownership, capacity, status, construction percentage completed and estimated on-line date of each these projects.

Table 1
Energy Commission-Approved Projects

Approved Projects (8/18/2003)	Ownership	Capacity (MW)	Status	Construct. Completed (%)	Current/ Estimated On-line Date
La Paloma	PG&E Natl.	1124	Operational	100	1/10-3/7/03
High Desert	Constellation	830	Operational	100	4/22/03
Elk Hills	Sempra & Oxy	500	Operational	100	7/23/2003
Huntington Beach Unit 4	AES	225	Operational	100	8/8/03
Valero Cogen. Unit 1	Valero Cogen. Unit 1	51	Operational	100	10/18/02
Los Esteros	Calpine Units 1,2,3&4	180	Operational	100	3/7/03
Tracy Peaker	GWF	169	Operational	100	6/1/03
Woodland II comb cyc	Modesto ID	80	Operational	100	6/6/03
Sunrise Comb. Cycle	Texaco & Edison	265	Operational	100	6/1/03
Blythe	Caithness & FPL	520	Construction	99	8/03
Pastoria	Calpine	750	Construction	49	6/3/05
Metcalf	Calpine	600	Construction	5	12/04
Mountainview	Intergen 3/	1056	Financing	15	6/05
Magnolia	SoCal Power Authority	328	Financing	0	5/05
Palomar Escondido	Sempra	546	Financing	0	8/4/05
City of Vernon Comb. Cyc.	City of Vernon Comb. Cyc.	134	Financing	0	6/05
Otay Mesa	Calpine	510	Const. on hold	5	12/04
Contra Costa	Mirant	530	Const. on hold	7	unknown
Russell City	Russell City -	600	on hold	0	unknown
Three Mountain	Covanta	500	on hold	0	unknown
Midway-Sunset	Mission Energy	500	on hold	0	unknown
Valero Cogen. Unit 2	Valero Cogen. Unit 2	51	on hold	0	on hold
United Golden Gate	El Paso	51	No site control	0	on hold
Approved Total		**10,100**			

In addition to Energy Commission-approved projects, there are 10,829 MW of projects under review or announced. **Figure 9** shows ownership and MW size for these projects. The capacity for projects actively under review totals 7,504 MW; in review but on-hold 2,335 MW; and announced 990 MW, for a total of 10,829 MW.

Figure 9
Projects Currently Under Energy Commission Review or Announced



Source: Energy Commission *Energy Facility Status Report* (8/18/2003)

Table 2 provides ownership, capacity, and other information on each one of these projects. This list includes East Altamont, 1,100 MW Calpine Project, which received Energy Commission approval on August 20, 2003.

Of the 9,839 MW projects under review, there were 7,504 MW under active review. EPG assumes that all of these projects will eventually be permitted, constructed, and become operational. However, of the projects under Energy Commission review but currently on-hold (2,335 MW), EPG assumes that only Potrero Unit 7 (540 MW) will become operational before 2030. This unit is likely to be constructed if transmission expansion into San Francisco load center is not constructed (the Jefferson-Martin 230 kV line) and the existing Potrero units are shut down as they get older and less reliable. In addition, EPG assumes that of the announced projects (a total of 990 MW), the San Francisco Reliability Peakers (180 MW), Roseville CT (150 MW), and Kings

River Conservation District Peakers (90 MW) will also be constructed. Based on these assumptions, the total capacity to be constructed by 2030 would be 8,464 MW.

Table 2
Projects Under Review or Announced

Projects in Review (8/18/2003)	Ownership	Capacity (MW)	Project Type	Estimated Decision Date	Estimated On-line Date
East Altamont*	**Calpine**	**1,100**	Green Field	**8/20/2003**	7/05
Pico Power Comb. Cyc.	Silicon Valley Pwr.	**147**	Brown Field	9/03	5/05
MID Simple Cycle	MID	**95**	Green Field	10/03	3/05
SMUD Comb. Cycle Phase 1	SMUD	**500**	Green Field	11/03	11/05
Morro Bay	Duke	**1,200**	Replacement	11/03	11/05
Salton Sea Geothermal	Cal Energy	**185**	Green Field	12/03	12/05
San Joaquin Val Energy Cntr	Calpine	**1,087**	Green Field	12/03	12/05
Walnut Energy Center	Turlock ID	**250**	Green Field	12/03	3/06
El Segundo Repower	Dynegy/NRG	**630**	Replacement	1/04	1/06
Inland Empire Comb. Cyc.	Calpine	**670**	Green Field	1/04	1/06
Blythe II Comb. Cyc.	Caithness&FPL	**520**	Green Field	4/04	4/06
Tesla Comb. Cyc	Florida Power& Light	**1,120**	Green Field	12/04	2/06
Total Projects in Active Review		**7,504**			
Potrero	Mirant	**540**	Expansion	on hold	on hold
Golden Gate	El Paso	570	Brown Field	on hold	on hold
Los Banos Peaker	Cummins	80	Green Field	on hold	on hold
Gilroy Phase I amendment	Calpine	45	Expansion	on hold	on hold
Avenal Comb.Cycle	Duke	600	Green Field	on hold	on hold
SMUD Comb. Cycle Phase 2	SMUD	500	Green Field	on hold	on hold
Total Projects in Review Currently on Hold		**2,335**			
Total Projects In Review		**9,839**			
Projects in Review (8/18/2003)	**Ownership**	**Capacity (MW)**	**Project Type**	**Estimated Decision Date**	**Estimated On-line Date**
SF Reliability Peaker 1	SF Reliability Peaker 1	**90**	Unknown	10/03	5/05
SF Reliability Peaker 2	SF Reliability Peaker 2	**90**	Unknown	10/03	5/05
Roseville Comb. Cycle	Roseville	**150**	Brown Field	10/03	6/06
Kings River Cons. Dist. Peaker	Kings River Cons. Dist.	**90**	Brown Field	11/03	12/04
Los Esteros Comb. Cycle	Calpine	70	Brown Field	11/03	unknown
National Power Combined Cycle	National Power	500	Green Field	7/04	unknown
Total Announced Projects		**990**			
Total Project In Review and Announced		**10,829**			
EPG Assumption of Total to be Constructed by 2030		**8,464**			

*East Altamont Project received Energy Commission approval on 8/20/2003

Renewable Resources

In SB 1078 (Chap. 576, Stat. of 2002) California mandated a Renewable Portfolio Standard (RPS) that requires the three investor-owned utilities (IOUs) to have sufficient renewable resources under ownership and/or contract to meet 20 percent of their energy requirements by 2017. EPG assumed that:

1. The 20 percent RPS mandate will remain the same after it has been reached, i.e., 20 percent will also be required in 2030.

2. This standard will also be followed by municipally owned utilities, i.e., 20 percent will apply for all of California.

3. Most renewable resources will be located in California. Therefore there will be no need to commit additional interstate transmission line capacity to meet this 20 percent mandate.

4. The average capacity factor from renewable resources will be 50 percent based on dependable capacity.

5. Existing renewable dependable capacity of 4,400 MW will remain available in 2030 either through repower or replacement.

Peak demand in 2030 is projected to be 80 GW, and the state's energy requirement is projected to be 400 billion kWh. Assuming 20 percent of this energy will be provided from renewable resources, the energy production from these resources will be 80 billion kWh by 2030. With a 50 percent capacity factor, the dependable capacity from renewable resources is estimated to be 18.3 GW. Subtracting the 4.4 GW of existing renewable resources means that over the next 27 years new renewable resources to meet RPS will be 13.9 GW. Thus the capacity of renewable resources will increase by over fourfold during this period.

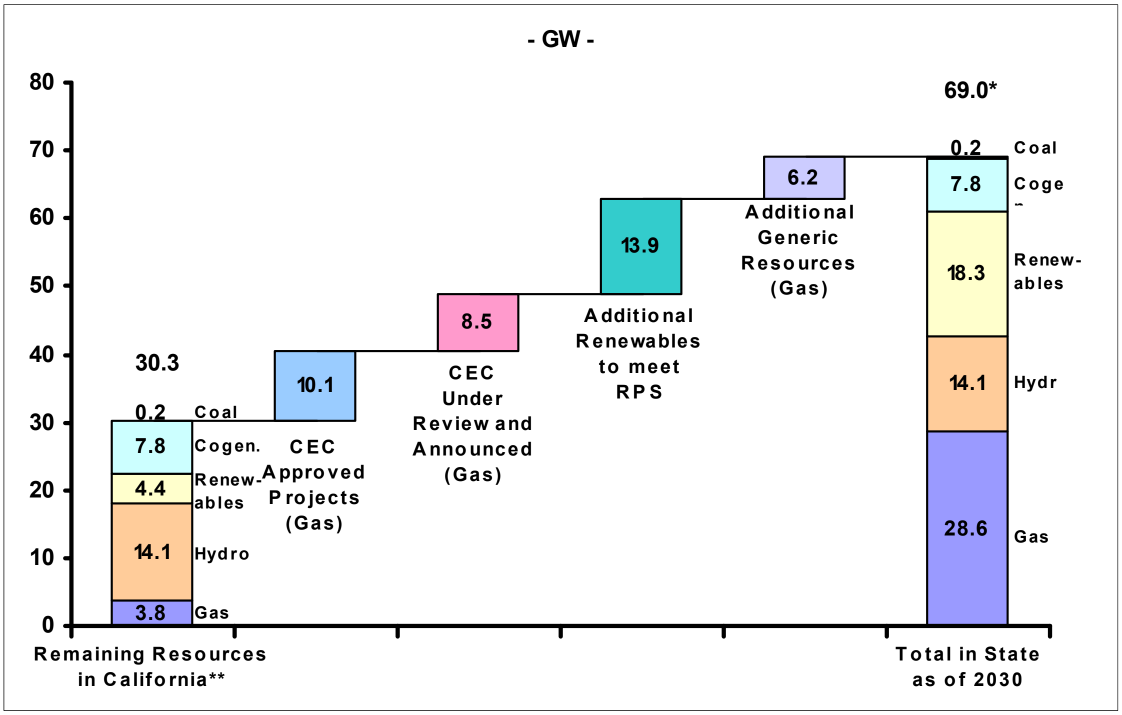
MEETING CALIFORNIA'S GENERATION RESOURCE NEEDS

The total capacity requirement for 2030 is projected to be 92 GW. With 32.1 GW of capacity remaining operational from the resource portfolio on-line as of January 2003, the need for new resources will be 59.9 GW.

If we assume that of the total capacity requirement 25 percent will be provided from import and 75 percent from in-state generation plants, then imported capacity will be 23 GW and in-state generation 69 GW.

Figure 10 shows an outlook for in-state generation capacity for 2030. Of the 69 GW requirements, available in-state capacity from current portfolio after requirements will be 30.3 GW. (This does not include 1.8 GW of out-of-state coal.) New resources in the pipeline and renewables, including 10.1 GW included in the list of Energy Commission's approved projects, 8.5 GW that are under review and announced, and 13.9 GW of new renewable resources for a total of 32.5 GW. To reach the 69 GW total, requires another 6.2 GW of new capacity, which would most likely be gas-fueled. Based on these assumptions, 36.4 GW of in-state capacity would be fueled by gas (28.6 GW of gas units plus 7.8 GW of cogeneration). This amounts to 52.8 percent of the total in-state capacity in 2030. The comparative percentage for January 2003 is 52.8 percent (32 GW out of a total of 60.6 GW).

Figure 10
California Generation Resource Outlook for 2030

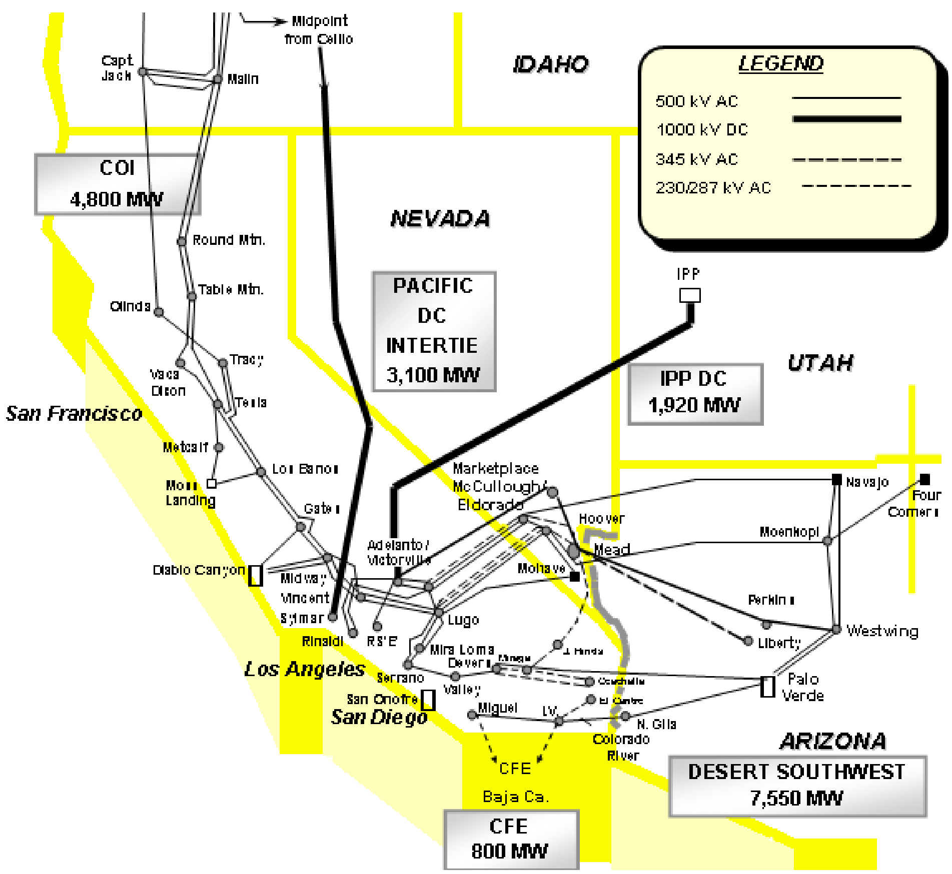


* 69 GW equals 75 percent of the total capacity requirement of 92 GW
** Excluding out-of-state coal projects, such as the Intermountain Power Project

TRANSMISSION INTERCONNECTIONS TO MEET FUTURE ELECTRICITY NEEDS

To supply 25 percent of peak demand from out-of-state resources means California will have to import 23 GW. All of the transmission capacity cannot be utilized simultaneously during the peak hours. We assume that, at a minimum, the 15 percent reserve transmission margin may be required. Therefore, to support 23 GW of firm capacity import during peak hours, the transfer capability for the interconnection system into California has to be around 26.5 GW. As shown in **Figure 11**, California's Extra High Voltage (EHV) transmission interconnection can import 18.2 GW. (This includes 7,550 MW of East of the Colorado River System (EOR) capability for the Desert Southwest (DSW). In this report, we are using EOR capability, since we are interested in firm import to California.) Thus California will need to add about 8.3 GW to the transmission interconnection capability over the next three decades, which would be equivalent to increasing the current interconnection capability by approximately 50 percent over this period.

Figure 11
California's 18,170 MW of EHV Transmission Interconnections



Figured 11 Continued

California Transmission System (MW)		Transfer Capability
Pacific Northwest	AC Intertie	4,800
	DC Intertie	3,100
Utah	Inter-mountain	1,920
Desert Southwest	Northern System	4,727
	Southern System	2,823
Mexico	Baja Region	800
Total		**18,170**

Initial options to increase interconnection capability that have been discussed or are under discussion include:

Devers-Palo Verde 2 with 1.4 GW of capacity to import from plants constructed around Palo Verde;

Doubling the transfer capability from Mexico to get access to power plants constructed in Baja California, 0.8 GW additional capacity;
Increasing the capacity to Utah-Wyoming by constructing another DC line or new 500 kV AC lines to double the existing capability to import output from coal plants, 2.0 GW additional capacity.

These projects will increase California's interconnection capacity by 4.2 GW. This still leaves a need to add another 4.1 GW of interconnection capacity. California needs to consider new interconnections to developing market hubs and resource- rich regions where new power plant development is likely to occur. There is considerable power plant activity in Baja California, as well as the potential for new LNG terminals. The DSW – Arizona, Nevada, New Mexico – has developed into a significant market hub. Power plants under construction or proposed around Palo Verde total over 6,000 MW. Also, the Utah-Wyoming area represents a resource rich region for gas, coal, and renewables. Consequently, future expansion options to be considered include:

New lines to the DSW, 1.3 GW;

Additional lines to Mexico, 0.8 GW, if a LNG terminal is constructed in Mexico;

New lines to Utah-Wyoming, 2.0 GW.

There would not be any addition to the PNW interconnection capability, as the existing 7.9 GW capability seems sufficient to carry out exchanges, summer capacity procurement and economy energy purchases from this hydro-rich region.

Table 3 shows the current and potential additional transmission capacity over the next three decades from different regions.

Table 3
California's Current and Potential Future Transmission Interconnections

Intertie Capacity (GW)	Current	Expansion Options under Discussion	Future Expansion Options	Total by 2030
Pacific Northwest	7.9	-	-	7.9
Inland Northwest	1.9	2.0	2.0	5.9
Desert Southwest	7.6	1.4	1.3	10.3
Mexico	0.8	0.8	0.8	2.4
Total	18.2	4.2	4.1	26.5

Of the 26.5 GW of transfer capacity potential for 2030, California would be able to count on 23.0 GW of firm import capability during peak hours. There will be 1.8 GW of existing out-of-state resources remaining in 2030; thus, California could conceivably pursue 21.2 W of new import resources.

The actual interconnections need to be planned based on an assessment of resource development potential, location of new market hubs, expansion of existing hubs, and coordinated planning with neighboring regions.

ENERGY MIX OUTLOOK FOR CALIFORNIA ELECTRICITY GENERATION

By 2030 the generation capacity requirement, including 15 percent reserve margin, will be 92 GW and the energy requirement, including transmission losses, will be around 400 billion kWh. **Table 4** shows an estimated capacity factor for resources and energy produced by each generation source.

Table 4 shows the projected energy production from California's gas fuel generation and also fuel requirements. The total gas fuel generation in state by 2030 will be 36.4 W. The energy generated from California's gas-fueled units will be 205.1 billion kWh, which is about half of the total net energy for required load.

Assuming an average heat rate of 8,000 Btu/kWh, the annual gas used in California for electricity production is projected to be 1,641 trillion Btu in 2030, versus California's 2001 gas consumption of 1,068 trillion Btu for electricity production. This means a 54 percent increase in gas consumption for electricity production over the next three decades, an annual growth rate of 1.5 percent. Projected annual growth rate for natural gas consumption in the *AEO* for the U.S. is 1.8 percent between 2001 and 2025. Therefore, the outlook developed for the generation mix in this report seems in line with national forecast for the natural gas consumption.

Table 4
Capacity and Energy Production for 2030
(Assumes 1.5 percent Load Growth)

Capacity Requirement = 92 GW Energy Requirement = 400 billion kWh			Capacity (GW)	Capacity Factor Assumed (%)	Energy Output (billion kWh)
Existing Resources	In State	Gas	3.8	60%	20.0
		Hydro	14.1	28%	34.6
		Renewable	4.4	50%	19.3
		Cogeneration	7.8	80%	54.7
		Coal	0.2	65%	1.1
		Sub-Total	**30.3**		**129.7**
	Out of State	Coal	1.8	65%	10.2
		Total	**32.1**		**139.9**
New Resources	In State	CEC Approved (Gas)	10.1	60%	53.1
		CEC Review (Gas)	8.5	60%	44.7
		Renewable	13.9	50%	60.9
		Additional Gas	6.2	60%	32.6
		Sub-Total	**38.7**		**191.3**
	Import	Northwest Southwest Mexico Inland Northwest	21.2	40%*	74.3
		Total	**59.9**		**265.6**
Grand Total			**92.0**		**405.5**

* The 40 percent capacity factor used for “New Imports” was derived based on the assumption of 20 percent capacity factor for Pacific Northwest imports and 50 percent capacity factor for imports from all other regions

ALTERNATIVE SCENARIOS AND IMPLICATIONS

A significant portion of power plants constructed recently are gas-fueled. A major consideration will be the availability of adequate natural gas supplies at reasonable prices to meet growing demand.

EPG has estimated the amount of natural gas that will be required to fuel power plants in California under different scenarios. The base case assumes 1.5 percent annual growth in electricity demand, 20 percent energy from renewables and 25 percent from imports. The generation capacity fueled by gas reaches 36.4 GW by 2030, including 7.8 GW of cogeneration. The natural gas requirement for power production reaches 1640 trillion Btu by 2030, a 60 percent increase over current use. For this scenario 8.3 GW of new transmission interconnection will need to be constructed.

If construction of the new transmission does not occur and the need for in-state generation increases to meet load growth, then the natural gas requirement will increase even further. Gas consumption may double from current levels. Such an increase may be unacceptable and infeasible as increased reliance on gas fuel, which would require new LNG terminals and pipelines and may be very expensive.

Different ways to reduce high dependency on natural gas may include: a higher goal for development of renewable resources, increased level of energy efficiency and conservation and, therefore, lower load growth, and increased imports fueled by abundant coal resources. Three scenarios are developed in this report to investigate the changes in the development of gas-fueled generation capacity in California, the amount of natural gas requirement for these generators, the level of additional transmission interconnections to support electricity import into California, and the amount of renewable capacity needed.

The three alternative scenarios are:

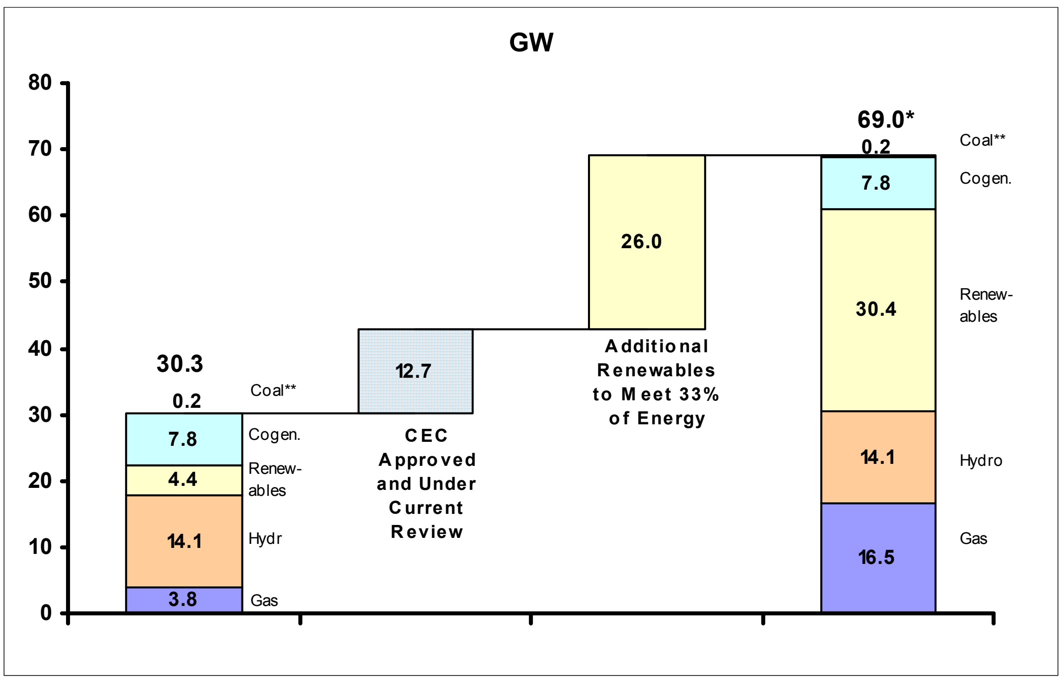
Higher Renewable Resources
Lower Demand Growth
Higher Import

Description of these three scenarios and impact on natural gas used for in-state generation and on expansion of transmission interconnection are provided in this section.

Higher Renewable Resources Scenario

In this scenario, renewable resources meet one-third of total energy requirements. The load growth remains at 1.5 percent per year as in the base case scenario. Therefore, by 2030 peak demand plus 15 percent reserve margin would be 92 GW and energy requirement would be 400 billion kWh. In order to produce one-third of the energy requirement from renewable resources, if the average capacity factor for these resources is 50 percent, then the installed capacity for renewable resources must reach 30.4 GW by 2030, producing 133.3 billion kWh of electricity. Current capacity for renewable projects is 4.4 GW. Attaining this level of installed capacity would require an additional 26.0 GW, or almost a sevenfold increase, in renewable resources capacity over the next 27 years. We assume that 75 percent of the total capacity requirement will be from California generation and 25 percent imported. **Figure 12** shows the generation resources outlook in California for 2030 for this Higher Renewable Resources scenario.

Figure 12
Generation Resource Outlook for 2030
With Higher Renewable Resources



* 69 GW equals 75 percent of the total capacity requirement of 92 GW
** Excluding out-of- state coal projects, such as the Intermountain Power Project

The total capacity of gas-fueled generation (gas fueled power plants and cogeneration) will reach 24.3 GW producing about 145 billion kWh with fuel usage around 1,130 trillion Btu. In addition, operational and reliability issues associated with intermittent nature of some of the renewable resources will need to be addressed. Also, the 30.4 GW of renewables represent firm on-peak capacity and will require construction of two to three times this amount to account for the intermittent nature of renewable resources.

Lower Demand Growth Scenario

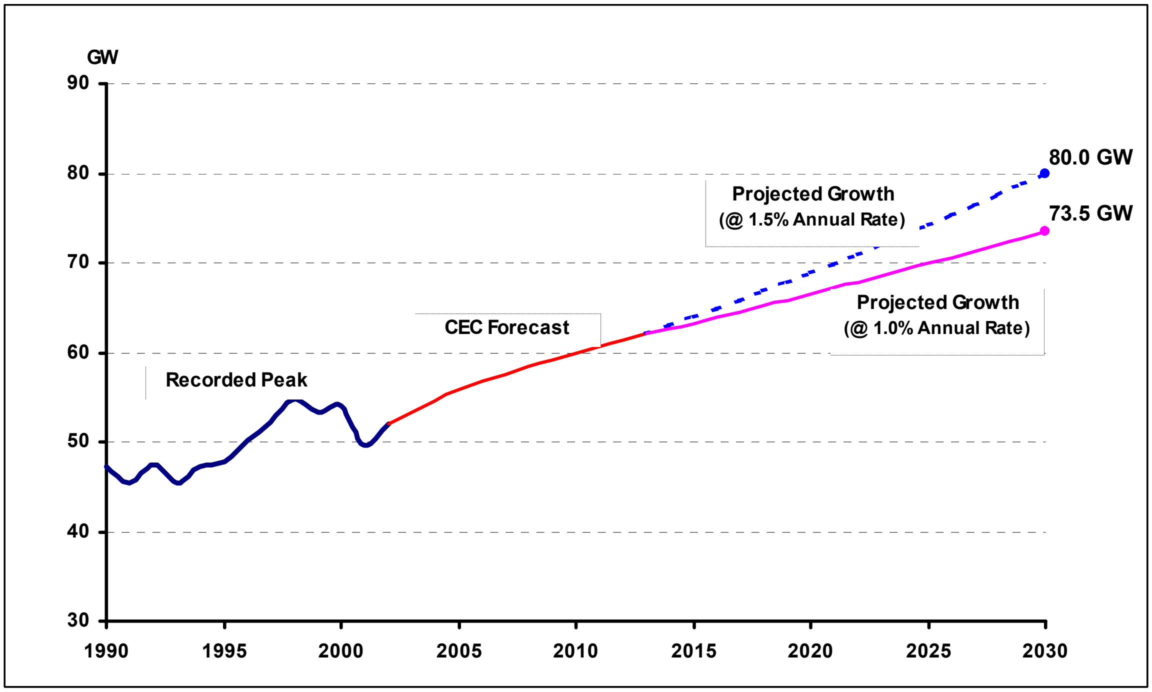
The demand forecast is subject to uncertainties due to economic growth, changes in productivity, the level of energy efficiency, and reliance on distributed generation at customer sites. In California, electricity use increased from around 50 billion kWh in 1960 to over 250 billion kWh by 2000. Total annual electricity use per capita grew from around 4 GWh in 1960 to about 6 GWh by 1970, a 50 percent increase over only a 10 year period. However, the growth in per capita electricity use has been very slow, around 0.1 percent per year since energy crisis of the early 1970s. The annual per capita use is now around 7 GWh and California is the most energy efficient state in the nation yet has the lowest electricity use per capita. While California has 12 percent of nation's population it uses only 7 percent of the nation's electricity consumption.

In the base case, the forecast using the U.S. Census projection assumes that California's population will reach 49.3 million by 2025, an increase of 56 percent from 1995-2025, a 1.5 percent annual growth rate. In the base case, per capita use of electricity was assumed to remain flat and, therefore, electricity use will increase at the same rate as the growth rate of population.

Taking into consideration some combination of lower population growth, high energy efficiency, higher demand growth, lower economic growth and an increase in distributed generation, a lower demand growth scenario has been developed. This scenario assumes 1.5 percent annual demand growth for the 2003-2013 period, consistent with the Energy Commission forecast, and a 1.0 percent annual demand growth for the period 2013 to 2030. Furthermore, with no changes in load factor, both energy and peak capacity would be growing at the same rate.

The projected peak demand in the lower demand growth scenario will be about 73.5 GW in 2030, as shown in **Figure 13**. This is approximately 6.5 GW lower than the base case projection. With a 15 percent reserve margin, the capacity required would be 84.5 GW. Assuming similar growth for energy, the annual energy requirement would be about 370 billion kWh.

Figure 13
California Peak Demand Outlook - Lower Demand Scenario



Considering that only 32.1 GW of power plants existing in 2003 will remain operational in 2030, the need for new resources from 2003-2030 will be 52.4 GW compared to 59.9 GW in the base case.

EPG assumes that 20 percent of the energy would be provided from renewable resources and that 25 percent of the total capacity required would be provided from imports.

Under this scenario, the need for new in-state generation during the period 2003-2030 is 33.1 GW compared to 38.7 GW in the base case. Furthermore, the need for additional imports is 19.3 GW compared to 21.2 GW in the base case.

Taking into consideration the transmission need for 1.8 GW of existing coal imports that will remain operational in 2030 and a reserve of 15 percent, the total intertie capacity requirement will be 24.3 GW. Additional transmission interconnections required under the lower demand growth scenario are around 6.1 GW, or almost a one-third increase from current capacity.

For this scenario, the total capacity of gas-fueled generation including cogeneration will reach 32.3 GW producing about 180 billion kWh with a fuel usage of around 1470 trillion Btu.

Higher Import Scenario

Under this scenario the load growth is assumed to be 1.5 percent per year. To reduce reliance on generation fueled by natural gas, 30 percent of the total capacity required is assumed to be provided by imports.

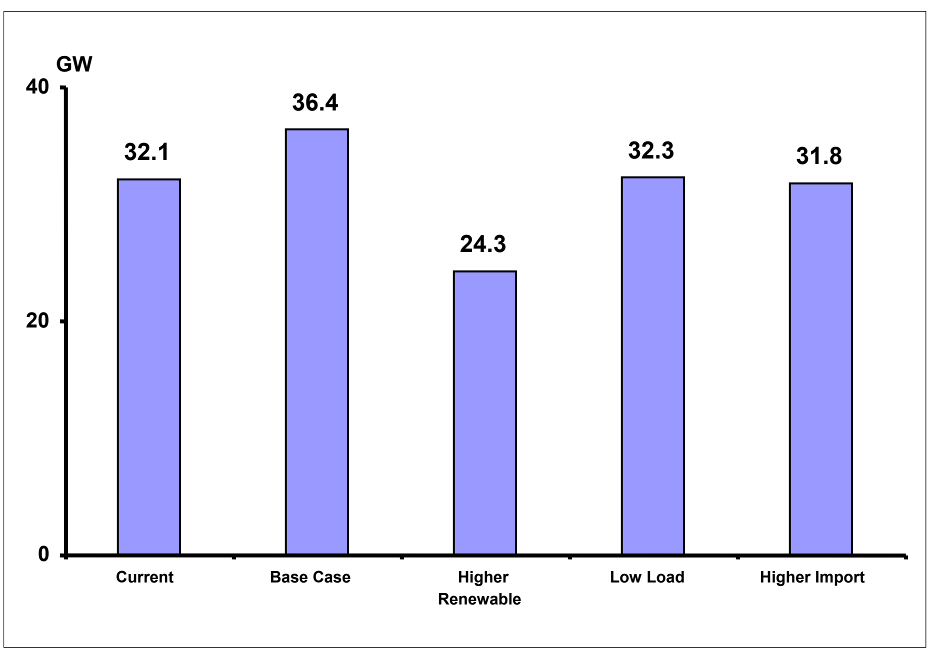
To meet 92 GW of need, 64.4 GW will be from in-state generation and 27.6 GW from imports. Taking into consideration the 20 percent of energy coming from renewables, the 31.8 GW of natural gas-fueled generation, including cogeneration, will produce 180 billion kWh and consume 1450 trillion Btu of natural gas.

The additional transmission interconnections required under the Higher Import Scenario are around 13.5 GW, taking into consideration the existing 18.2 GW of capacity and 15 percent reserve.

Comparison of Scenarios

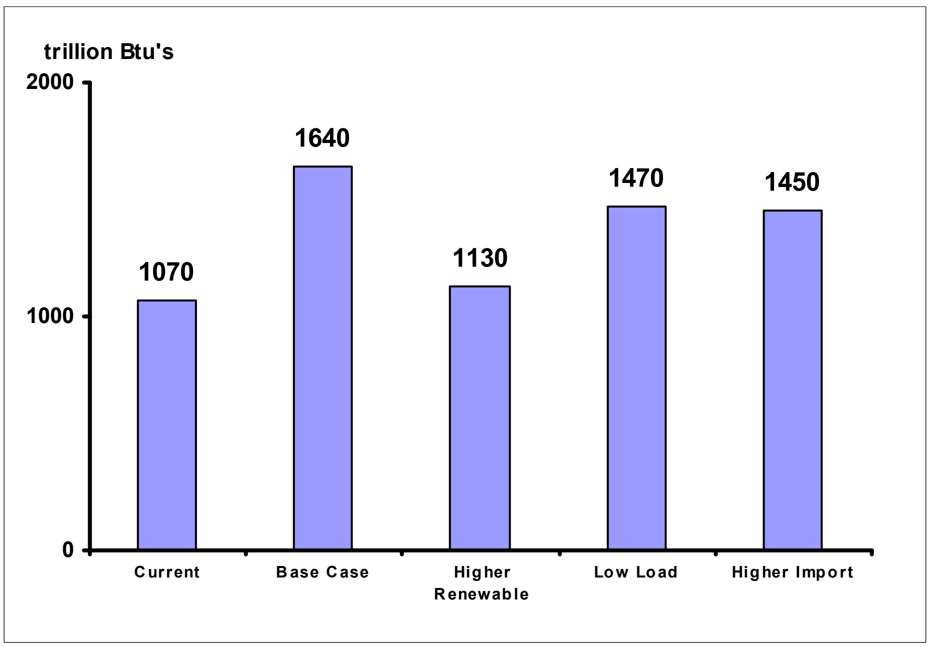
The gas-fueled generation capacity under different scenarios is shown in **Figure 14**. The gas-fueled generation capacity can be maintained at its current capacity of approximately 32 GW in the lower load and higher import scenarios, and can be reduced to 24 GW under the high renewables scenario.

Figure 14
Gas Fueled Generation Capacity –
Current and for 2030 Under Different Scenarios



The 2030 natural gas requirement for power generation can be decreased from the 1,640 trillion Btu in the base case either by increasing the generation from renewable resources above the 20 percent goal or by reducing annual load growth from 2013-2030 from 1.5 percent to 1.0 percent, or by increasing imports with the construction of new transmission interconnections increasing from 8.3 GW to 13.5 GW. This is shown in **Figure 15**.

Figure 15
Natural Gas Requirement for In-State Generation --
Current and for 2030 Under Different Scenarios



The need for new transmission interconnections is 8.3 GW in the base case, and ranges from 6.1 GW to 13.5 GW in the different scenarios, as summarized in **Figure 16**.

Figure 16
Transmission Interconnection Capacity Under Different Scenarios

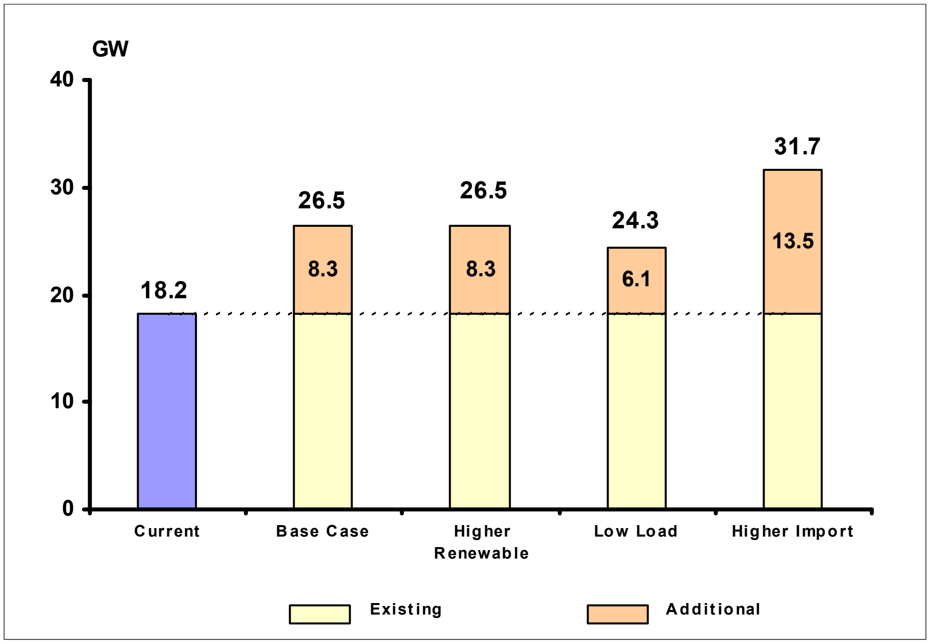
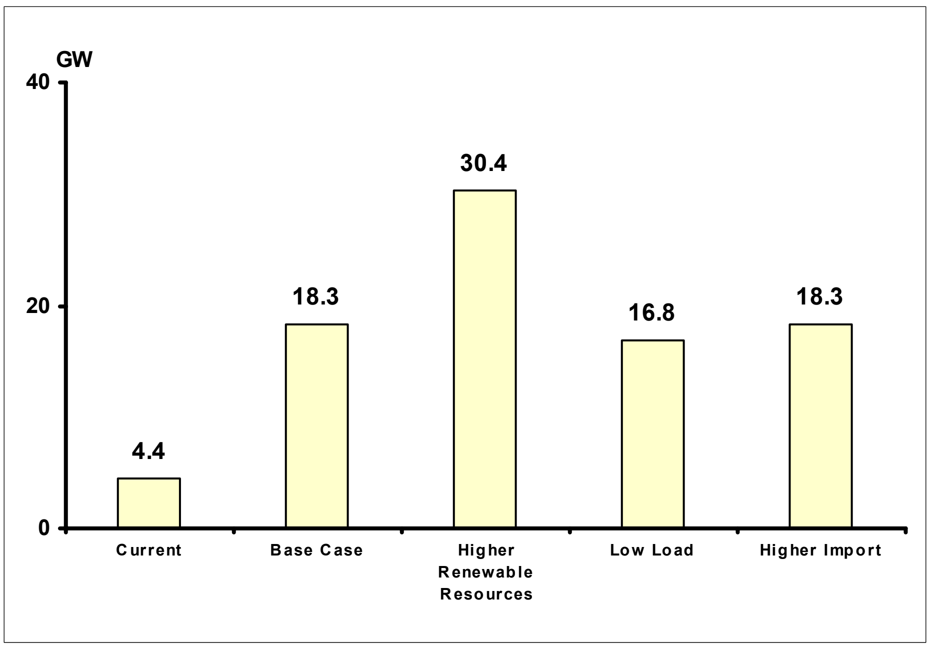


Figure 17 shows the new capacity from renewable resources under different scenarios. The current level of renewable capacity operating in California is 4.4 GW (excludes conventional hydro). This is estimated to increase to 18.3 GW in the base case, assuming a 20 percent target for energy from renewables. With a target of one-third energy from renewables, the capacity from renewables is 30.4 GW. Because of their intermittent nature, high levels of renewables development raise important operating and reliability issues. Also, achieving a 20 percent penetration from renewables by 2030 translates to a fourfold increase, an aggressive target.

Figure 17
Renewable Capacity Under Different Scenarios



Firm On-Peak Capacity. Due to intermittent nature of renewable resources, actual installed capacity is estimated to be two to three times the amount of renewable firm on-peak capacity required.

PLANNING CALIFORNIA'S FUTURE TRANSMISSION INTERCONNECTIONS: POLICY ISSUES AND RECOMMENDATIONS

California's transmission interconnections have played a vital role in meeting electricity needs reliably and cost-effectively. However, due to the changing industry structure and financial uncertainties, California has not addressed the need for new interconnections or built new transmission capacity since the mid-1990s.

Looking ahead 25 to 30 years, several trends are clear – California's population and economy are forecast to grow, aging power plants will retire, additional power supplies will be needed, and strategic new interconnections to neighboring states will play an important role in meeting these needs. While the precise timing of these trends can be debated, it is clear that California must plan now for future transmission interconnections. Key policy issues and recommendations are discussed below.

Planning for Transmission Interconnections Requires a Long Term Horizon

In recent years, the planning horizon has shrunk to focus on power needs three to five years out. While this is adequate for combustion turbine peaking and combined-cycle projects, it is not enough lead-time for planning major transmission interconnections. Major transmission projects have approximately a ten-year lead-time. Projects involving multiple states require close coordination on corridor planning. However, reliable information on planned new generation projects available from the independent power producers is lacking.

Consequently, transmission is always playing "catch up" to generation projects and will continue to do so unless the planning process is changed to encompass a longer-term time horizon. While it is hard to predict which power plants will be built where, it is clear that electricity is dependent on the availability of fuel – gas, coal, renewables. Hence, California needs to assess resource availability and emerging electricity market hubs that may evolve and develop a long-term transmission interconnection plan to access these regions.

Transmission Interconnection Planning Methodologies Need to be Reconsidered and Revised

Transmission interconnections offer strategic benefits that are not well reflected in traditional analytic approaches. For example, reliance on present value analysis using a high cost of capital discounts benefits beyond the first ten years. However, most transmission project benefits start to assert themselves after the first five to ten years of operation, as was the case with the Pacific AC Intertie and other interconnections. Also, many of the benefits are insurance that transmission projects provide against contingencies and during short duration abnormal conditions whose values are not captured in current planning approaches.

California Should Develop a Unified Vision and Strategic Plan for Future Interconnections With Neighboring Regions

The first step in addressing future interconnections is a unified vision and a strategic plan. Looking ahead to 2030 makes it clear that new interconnections will be needed. With this as a starting point, the focus needs to be on how many interconnections and to what regions?

Again, the precise timing of when these interconnections will be needed is less important than building consensus on need and location. California can then work with neighboring regions to develop:

Interconnection plans;

Corridor and right-of-way plans;

Streamline siting and permitting for multi-state projects.

This is the equivalent of site banking whereby corridors and interconnections are identified but the actual project decision deferred until need asserts itself. This will reduce project lead-time and provide planning flexibility to meet future needs.

Streamlining and Coordinating Planning and Permitting in California

The interconnection planning process needs to be segmented into a strategic phase and a permitting phase. The strategic phase should be designed to:

Focus on a 25-year planning horizon;

Build consensus on the need for interconnections;

Assess resource potential and market hubs to identify potential interconnection projects;

Work with neighboring states to build consensus on interconnections, corridors and projects.

The permitting phase should be designed to:

Focus on specific projects needed in the next 5 to 10 year window;

Streamline assessment of need;

Establish valuation methodologies that address strategic and insurance value of transmission.

In addition, regulatory steps need to be taken now to make sure that timely steps are taken by utilities to acquire needed rights-of-way and to bank them, as well as to establish mechanisms for covering costs associated with right-of-way acquisitions and corridor planning.

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